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# Meeting Atmospheric Modeling Requirements for Utility Data

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| Atmospheric Models | Stationary Sources | 04A |
| Mathematical Models | | 12A |
| Utilities | | |
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## ABSTRACT

The purpose of this paper is to examine emission inventory data available for the utility industry and determine how well those data meet atmospheric modeling requirements. Utilities are important from the perspective of their contribution to total $SO_2$ and $NO_x$ emissions, and also because there are data reporting requirements for utility plants that allow consistent emission estimates to be made for each U.S. facility. It was found that publicly available data on utilities can be used to estimate plant and unit level emissions by month using consistent methods. Needs for data for time periods of less than a month (weekly, daily, hourly) are more difficult and costly to meet. Continuous emission monitoring data hold promise for providing emissions information for time periods as short as 1 hour, but these instruments are in place at a limited number of units. Hourly emissions for non-monitored units would have to be estimated using rough approximations such as seasonal hourly load profiles. If it is important for modelers to know that utility units were not operating for a day or a week during a certain period, then special studies would have to be instituted to collect this information.

## INTRODUCTION

Because the level of sophistication of atmospheric dispersion modeling has increased over time, especially in the acid rain area, the needs for emission inventory data have become more comprehensive. Formerly, data on source coordinates, stack parameters, and annual emissions were sufficient to exercise any dispersion model. Recently, however, there have been calls for seasonal, monthly, weekend/weekday, and even hourly emission breakdowns. Modelers have also requested data for more than just the standard set of criteria pollutants. Size distributions for particles are also of interest.

The purpose of this paper is to examine data available for the utility industry and determine how well those data meet modeling requirements. The utility industry differs from other pollutant emitting sectors because both the industry and the Federal government use a standard set of reporting requirements for utility units, which means that data of consistent quality are available across the entire sector.

This paper also describes recent analyses performed using the available data on electric utilities for the National Acid Precipitation Assessment Program (NAPAP). Under sponsorship of the U.S. Environmental Protection Agency (EPA) through NAPAP, E.H. Pechan & Associates, Inc. (Pechan) has been involved for the last several years in the development of methods to estimate utility emissions.

The utility data base used to develop the emission estimates presented in this paper is also being used as part of the Acid Deposition Emission Inventory, which is being developed by EPA to support NAPAP task groups on anthropogenic sources and atmospheric processes. In 1980, Congress established NAPAP to coordinate and expand research relevant to the problems posed by acid deposition in and around the United States. The program is organized and managed through the Interagency Task Force on Acid Precipitation with subordinate task groups coordinating specific technical areas of research. One of these task groups is studying anthropogenic sources, and one of its major objectives is to provide an accurate and complete inventory of emissions from anthropogenic sources believed to be important in acid deposition processes.

## MODELING NEEDS

From a modeling perspective, an emission data base should contain comprehensive information on flow rates of pollutants discharged into the atmosphere, location of the sources, temporal variations (seasonal, weekly, and diurnal) in these emissions, and stack characteristics. Models with a rigorous treatment of chemistry typically require the emissions of the following pollutants or classes of pollutants: $SO_2$ and sulfate ($SO_x$), NO and $NO_2$ ($NO_x$), reactive hydrocarbons, $NH_3$, alkaline and trace metals, particulate matter, and CO. Furthermore, information should be available to allow the modeler to distribute the reactive hydrocarbon emissions into different classes.[1]

In order to see how well the above modeling needs can be met, we have focused on data available for the utility sector. Utilities are important from the perspective of their contribution to total $SO_2$ and $NO_x$ emissions, and also because there are data reporting requirements for utility plants that allow consistent emission estimates to be made for each U.S. facility. Using previous estimates of utility emissions performed by Pechan as an example, this paper examines how well modeling requirements can be met. Annual emission estimates are described first, followed by monthly, then hourly estimates.

## PRIMARY DATA SOURCES

While numerous data sources are available for use in estimating utility emissions, the ones we have found most useful are listed in Table I. The Energy Information Administration (EIA) Form 759 collects monthly data on net generation, consumption of coal, oil, and natural gas, and end-of-the-month stocks of coal and oil for each plant by prime mover for all electric generating utilities. (In January 1982, the Federal Power Commission (FPC) Form 4 was superseded by EIA Form 759.) The Federal Energy Regulatory Commission (FERC) Form 423 is a monthly record of all fossil fuels delivered to generating plants that have a steam-electric generating capacity of 50 MW or larger. Important fuel data available from this form include fossil-fuel deliveries, average fuel heat content, sulfur content, ash content, and cost. EIA Form 767 is an annual report that contains fuel consumption data by unit, plus information on the physical characteristics of the plant (stack parameters and emission control equipment) for large steam plants (over 100 MW). (Beginning with 1982, EIA Form 767 replaced FPC Form 67.) EPA's Utility Flue Gas Desulfurization (FGD) survey provides information on operational and planned utility FGD systems.[2]

Applications of these data sources to estimate utility emissions are presented in the sections that follow.

## ANNUAL EMISSION ESTIMATES

The most comprehensive national analysis of utility $SO_2$ and $NO_x$ emissions and supporting data was performed by Pechan in preparation of the NAPAP Utility Reference File (NURF), which is based on data representing 1980 conditions.[3] Figure 1 provides an overview of the NURF data system. NURF consists of a variety of physical elements including data files and computer programs. Together, these can most conveniently be conceptualized as four logical component files: (1) the master unit data file (containing information on all generating units), (2) the fuel specific emissions file (containing information on all fossil fuel-fired electric utility generating units), (3) the stack parameters file (containing stack information on a unit-specific basis), and (4) the announced unit file (containing unit-specific information on units coming on-line or converting to coal-firing after 1980). While the four NURF components discussed above do not exist in a distributable form, three files derived from NURF have been made available for distribution: (1) the NAPAP inventory updates file (containing corrections and addendums to the existing NAPAP inventory), (2)

the Unit Inventory (an updated version of the previously developed file of the same name containing unit-specific information on larger generating units and aggregated information on smaller units), and (3) the announced inventory (containing information on units coming on-line or planned for conversion to coal after 1980). The NAPAP inventory updates file is the one of primary interest to atmospheric modelers.

In the NAPAP inventory updates file, point source data are provided for each plant emitting 100 tons per year or more of $SO_2$, $NO_x$, or particulate matter. For smaller plants, emissions and fuel use are aggregated at the county level in the NAPAP area source component of the NAPAP emission inventory.

The NAPAP point source inventory is segmented into three types of data: plant data, point data, and source classification code (SCC) data. Plant data are those values which are the same for the entire plant. In the original NAPAP point source inventory, a point can be an individual emitting combustor (e.g., a boiler) or can comprise more than one such combustor if their characteristics are the same. In NURF, identical combustors are split into separate points. SCC data refer to the individual processes within each emitting point. For utilities, there is a separate SCC for each fuel type burned in the combustor.

Point level data of interest to modelers include Universal Transverse Mercator (UTM) coordinates, throughput by season, hours of operation (hours, days, weeks), combustor capacity, stack parameters, and control equipment and its efficiency. SCC level data include fuel quantity used, hourly design rate, fuel sulfur, fuel ash, and fuel heat content.

Figure 2 shows the hierarchy of NURF data sources by data element. Thus, EIA Form 759 was the primary source of fuel consumption data at the plant level. FPC Form 67 was a secondary data source on fuel use and was used to allocate plantwide fuel use to specific units.

Summary results of the 1980 NURF analysis are shown in Table II. This table shows the importance of coal-fired units to total $SO_2$ emissions; coal steam is 91 percent of the emissions total. Thus, except in regions where coal-fired utilities do not dominate, such as New England, inventory efforts are best spent on coal plants.

From our past work, we have determined that the most significant variables affecting annual $SO_2$ and $NO_x$ utility emission estimates are fuel use, fuel quality, and control equipment efficiency. Important issues associated with preparing accurate estimates for each of these variables are described below.

Determining fuel use at the plant level is facilitated by the availability of EIA Form 759. A much more difficult issue is the correct assignment of fuel use to units. Because FPC Form 67 contains unit level information, it can be used to allocate fuel use to units. This type of allocation must be made with care, however, because utilities can report fuel

quality on Form 67 on either an "as burned" or an "as received" basis. A review of a sample of hard copy Form 67 submissions showed that as many plants reported fuel quality "as received" as reported it "as burned." Thus, assuming that all Form 67 data are submitted on an "as burned" basis can lead to significant errors in results.

Correct allocations of fuel use to units are especially important in plants which have control equipment on some units, but not others. The simplest example would be a plant with two units: unit 1 having an $SO_2$ scrubber and unit 2 having no $SO_2$ controls. If the plant burns both high and low sulfur coal, the correct allocation of low sulfur coal to the uncontrolled unit and high sulfur coal to the scrubbed unit is important. Otherwise, emission estimates can be significantly in error.

Another important factor in $SO_2$ emission estimation is the fuel sulfur content. For the larger coal-fired units, a difference of 0.1 percent can produce emission differences of more than 10,000 tons annually. The number of significant figures used for fuel sulfur content is also critical. Pechan has adopted the convention of using fuel sulfur content to the nearest hundredth of a percent. This matched well with the data reported to DOE and the size of data fields typically available for these data in EPA's National Emissions Data System (NEDS).

As shown in Figure 2, the primary data source on $SO_2$ control equipment was the Flue Gas Desulfurization Information System (FGDIS). Because design control efficiencies have been used to estimate $SO_2$ removal, there is concern that design efficiency is an unrealistic estimate of actual effectiveness. There are really two concerns here: one is that scrubbers may not always be operating when the unit is operating, and the other is that, when the scrubber is operating, the actual removal rate differs from the design rate. Limited data available in FGDIS can be used to address the first concern. FGDIS contains data on FGD system operability, which is the hours the FGD system was operated divided by boiler operating hours in the period. In the FGDIS, an operability value is potentially reported for every month. These monthly values can be used to estimate an average operability value for a year. This value can then be used t estimate the $SO_2$ device gas bypass fraction by subtracting it from one (1-operability). Data are not always complete in this file, though, because data submission is voluntary. A potential problem with this measure is that units can be considered operating when they are burning small fuel quantities in start-up or standby modes, and the scrubber is not operating during these periods. If these standby or start-up periods are lengthy, applying an average operability value will underestimate the actual removal performance of the scrubber.

Information on actual removal performance is more difficult to obtain. Continuous emission monitors (CEM) at a limited number of power plants can be used to analyze control equipment effectiveness. Analyses to this point have shown that actual control effectiveness can be either better or worse than indicated by design information. Emission estimates for scrubbed units from CEM data may differ from those calculated from design information by a factor of two.[4] While the effect of taking actual FGD performance into account

is not likely to be significant in 1980, it will become increasingly important in future years.

Thus, experience in estimating annual $SO_2$ and $NO_x$ emissions shows that the important variables are fuel quantity burned, the emission factor appropriate for each fuel, firing type and bottom type configuration, the sulfur and ash content of the fuel, and the efficiency of the control equipment, if it exists.

## MONTHLY EMISSION ESTIMATES

Monthly $SO_2$ and $NO_x$ emissions can also be estimated using publicly available data on utility operations. The most straightforward method for doing this is to allocate existing annual emission estimates to months using the Form 759 fuel consumption data for each plant. However, as the DOE collection instruments can be (and have been) changed from year to year, the best approach for estimating monthly emissions for a given year depends on the data available. Work recently completed to estimate 1981 monthly emissions is presented here as an example.[3]

Primary data on steam units were obtained from NURF and 1981 FPC Form 67 submissions. NURF is the source of physical characteristics (burner type, capacity, pollution control equipment). The 1981 FPC Form 67 supplies fuel use by boiler or, if appropriate, by fuel feeder. For plants not represented by Form 67 (smaller than 25 MW capacity), fuel use was allocated based on unit capacity.

For each month, unit level shares of fuel consumed were calculated for coal, oil, and natural gas. These shares were then normalized so that the sum of monthly fuel use for each fuel over all units at each steam plant was 1.0. Individual unit fuel use was then estimated by applying the monthly shares to the actual fuel consumption for the month reported on Form 759. This method was designed to correct fuel use unit errors which occur often on Form 67.

For nonsteam units (e.g., turbines), fuel shares were allocated based on fuels which can be used at the unit. Since monthly unit level fuel use data are not available for nonsteam units, the unit level shares of the plant-level fuel consumption were assumed to be the same for each month and were calculated based on unit capacity. As with the steam units, these shares were normalized to 1.0 and then applied to estimate monthly fuel use by unit.

Fuel quality was then obtained from Form 423 for plants of more than 50 MW capacity. State average fuel qualities were used for smaller plants. Fuel consumption and quality data were then used along with control equipment efficiency to estimate emissions.

Monthly trends in $SO_2$ and $NO_x$ emissions are illustrated in Figure 3. On a national level, the seasonal effect was more pronounced for $SO_2$ than it was for $NO_x$. Throughout the year, coal related emissions dominated. While coal related emissions showed less relative variation than oil related emissions due to the use of coal as a base load fuel, the

magnitude of coal related emissions was so great that their variations overwhelm the effects of all other variations. Strong winter and summer peaks were apparent in these results. The summer peak occurred in July and the winter peak in December/January.

Fuel use and resulting emissions showed much larger variation at the state and regional level. While, on a national basis, emissions and coal use had both winter and summer peaks, most states showed either a winter peak (northern states) or a summer peak (southern states), and the timing and magnitude of these peaks were weather related. Regional $SO_2$ emissions by month are illustrated in Figure 4. Emissions from the Midwest dominated as illustrated by the close resemblence of the national monthly trend totals in Figure 3 to the Midwest monthly trend in Figure 4. Other significant regions were the Southeast and Northeast. The Midwest region was characterized by a modest winter peak, the Southeast region showed a clear summer peak, while the Northeast showed a pattern similar to that of the Midwest. Emissions from the other regions were low in all months.

## HOURLY EMISSION ESTIMATES

When utility emission estimates are required for time periods shorter than 1 month, there is no reliable source of information which can be used to produce these estimates for all of the large utility emitters in the continental United States. As was mentioned earlier, CEMs are a promising data source for those units that are monitored. However, the number of units that are monitored is limited. Fifty monitors are in place at electric utilities in Pennsylvania, and these monitors are used by the Commonwealth of Pennsylvania for enforcement. In addition, there is a requirement for continuous $SO_2$ and $NO_x$ emission monitoring at new large coal- and oil-fired steam generators, but these are well controlled facilities and not generally among the highest emitters. Although the number of utility units with CEMs is increasing, data from monitors are not available from all units. Thus, there are two difficulties associated with CEM data: (1) an alternative emission estimation method is needed for non-monitored units, and (2) there is no current mechanism for retrieving and processing the CEM values.

An alternative method for estimating diurnal changes in utility unit emissions is to apply the available data on hourly loads by unit by month. FPC Form 12 provides hourly load profiles by month for selected facilities. These data could then be assembled in matrix form with profiles sorted by region, season, and fuel type. Profiles could then be selected from the matrix to match each unit in the emission inventory to provide estimates of diurnal emission changes. There are certainly weaknesses in such an approach. It assumes that utilities dispatch their plants in the same way each day in order to meet electricity needs. Thus, units may be shut down for maintenance, and, although this will change unit operations, these emission changes will not be reflected in the inventory.

The result of the above discussion is that no methods exist for establishing a data set of consistent quality for estimating hourly utility emissions. This may pose problems for modeling exercises that attempt to

simulate conditions for a few days where results could be affected by unusual emissions at a single plant. Thus, care should be taken when reviewing modeling results to ensure that what is being observed reflects reality and is not an artifact of the data, instead.

## RECOMMENDATIONS AND CONCLUSIONS

While the utility sector has more data available than others for the purposes of providing data needed by atmospheric modelers, there are limitations which should be recognized by both inventory developers and dispersion modelers. Conclusions based on previous Pechan work along with suggestions for future work are offered below.

1. Estimating utility emissions from data reported to the U.S. Department of Energy (DOE) is more than merely a data processing exercise. Some data sets are more accurate than others, and applications of these data should take into account the possible reporting problems.

2. The publicly available data on utilities can be used to estimate plant and unit level emissions by month. Needs for data for time periods of less than a month (weekly, daily, hourly) are more difficult and costly to meet. CEM data hold promise for providing emissions information for time periods as short as 1 hour, but these instruments are only in place at a limited number of units. Hourly emissions for non-monitored units would have to be estimated using rough approximations such as seasonal hourly load profiles. If it were important for modelers to know that utility units were not operating for a day or a week during a certain period, then special studies would have to be instituted to collect this information.

3. More effort spent on ensuring that coordinates for power plant stacks are correct would be helpful. Guidance is needed from modelers on whether this effort should focus on only the largest emitters and whether individual stack coordinate differences are important (i.e., if it is necessary to know that there are four stacks that are 50 m apart or if knowing the location of stacks to the nearest kilometer is sufficient).

4. All data sources are not created equal. Survey designs and the quality assurance performed on the responses are both important. Experience has shown that data files which are used to generate published reports are most reliable.

5. NURF is a primary example of a data file which has been developed using consistent methods to meet the needs of atmospheric modelers, policy analysts, and economic modelers. If utility inventories are developed for acid deposition inventories that do not use consistent methods, their usefulness for developing policy insights and evaluating strategies will be limited.

## ACKNOWLEDGEMENTS

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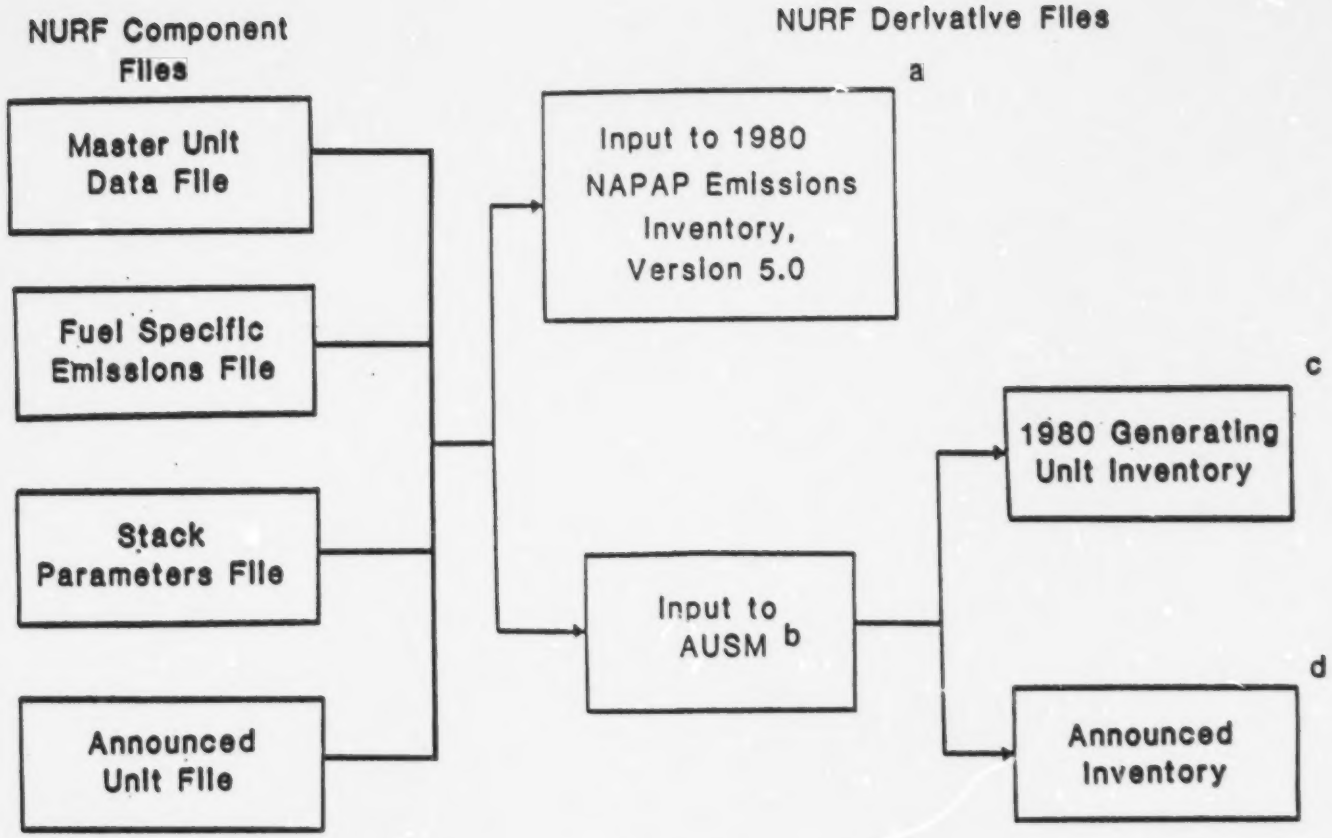
Table I. Primary data sources used in the NAPAP utility reference file.

| Data Available | Sources of Data | Coverage | Reporting Cycle |
|---|---|---|---|
| Installed Nameplate Capacity<br>Net Generation<br>Fuel Consumption<br>Fuel Stocks | Form EIA 759<br>Monthly Power Plant Report | All electric utilities with generating plants, accounting for 100 percent of electric utility generation | Monthly |
| Fuel Receipts<br>Fuel Cost | FERC Form 423<br>Monthly Report of Cost and Quality of Fuels for Electric Plants | Fossil-fuel plants with an installed nameplate capacity of 50 MW or larger | Monthly |
| Monthly Fuel Consumption by Unit<br>Stack Parameters<br>Emission Control Equipment | EIA Form 767<br>Steam-Electric Plant Operation and Design Report | Fossil-fuel plants with an installed nameplate capacity of 100 MW or larger | Annual |
| Operational and Planned Utility FGD systems | FGDIS<br>Flue Gas Desulfurization Information system | Electric utilities with operating or planned FGD systems | Quarterly |

Table II. 1980 NURF summary statistics by plant type.

| Plant Type | Capacity (MW) | % of Total | Generation (TWh) | % of Total | $SO_2$ ($10_3$ tons) | % of Total | $NO_x$ ($10_3$ tons) | % of Total | TSP ($10_3$ tons) | % of Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Coal steam | 242,700 | 42 | 1,171,000 | 51 | 16,070 | 91 | 5,200 | 79 | 570 | 88 |
| Oil steam | 67,600 | 11 | 217,000 | 10 | 1,320 | 8 | 400 | 6 | 60 | 9 |
| Gas steam | 93,500 | 16 | 338,000 | 15 | 120 | 1 | 750 | 12 | 20 | 3 |
| Oil nonsteam | 29,300 | 5 | 7,000 | 0 | 10 | 0 | 40 | 1 | 3 | 0 |
| Gas nonsteam | 24,400 | 4 | 21,000 | 1 | 0 | 0 | 100 | 2 | 2 | 0 |
| TOTAL FOSSIL | 457,500 | 78 | 1,754,000 | 77 | 17,520 | 100 | 6,490 | 100 | 655 | 100 |
| Nuclear | 48,900 | 8 | 233,000 | 10 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydroelectric | 81,500 | 14 | 287,000 | 13 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other | 900 | 0 | 5,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 588,800 | 100 | 2,279,000 | 100 | 17,520 | 100 | 6,490 | 100 | 655 | 100 |

Note: Percentages calculated from detailed data.



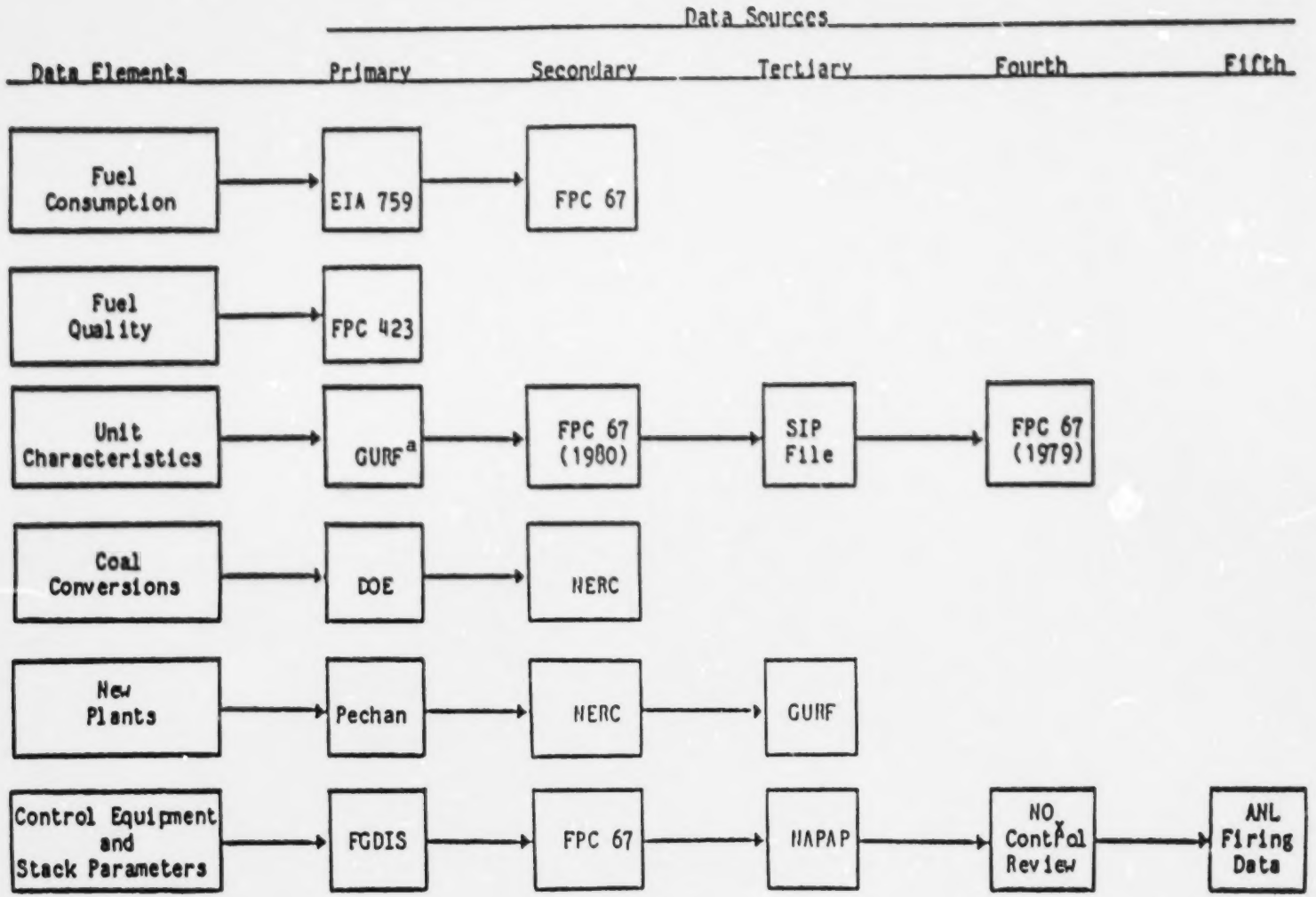

[a] existing plants emitting $SO_2$, $NO_x$, or TSP

[b] Advanced Utility Simulation Model

[c] existing plants aggregated

[d] planned plants (or conversions)

Figure 1. Overview of NURF elements.




[a]Generating Unit Reference File

Figure 2. Hierarchy of NURF data sources by data element.

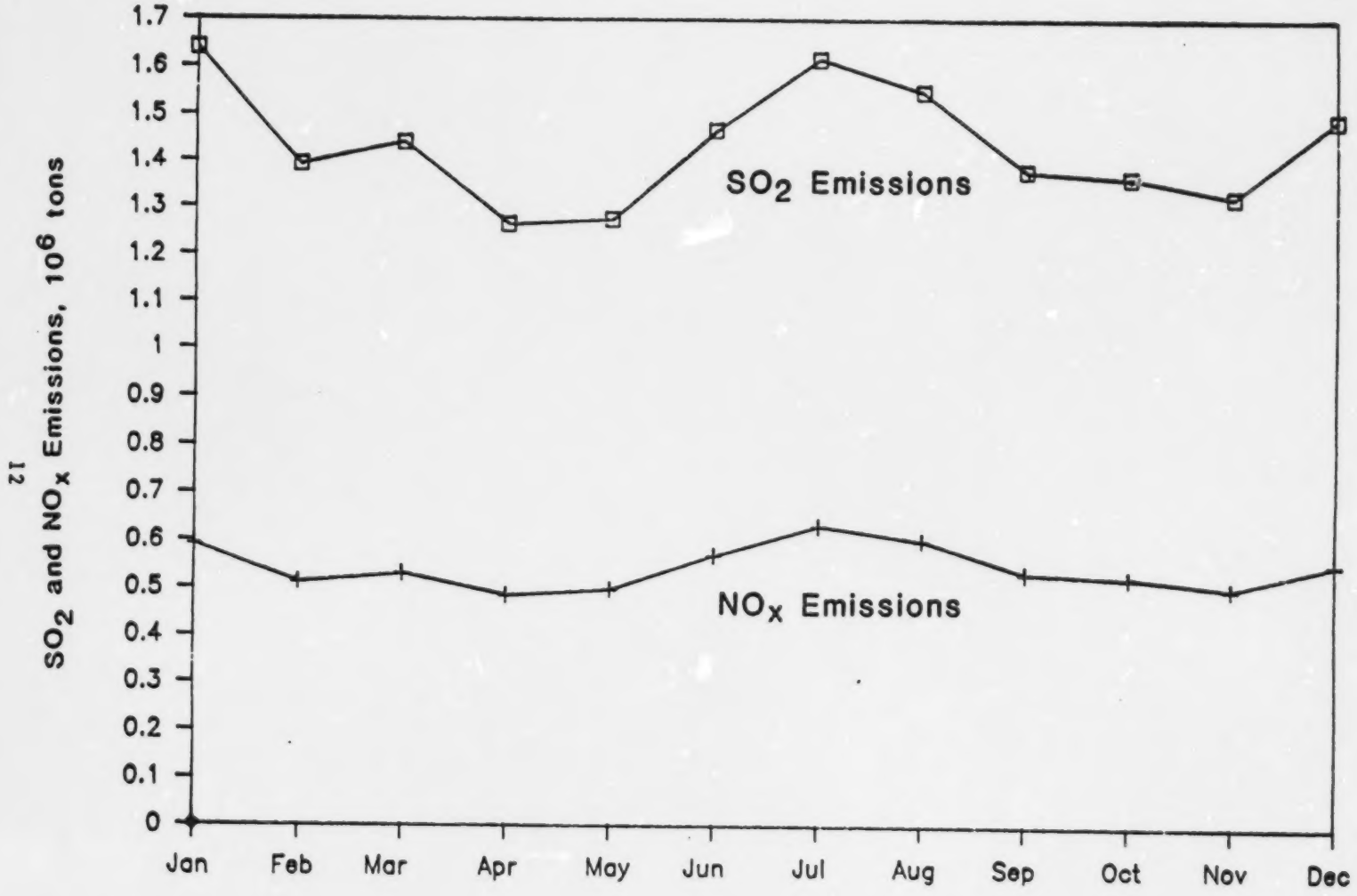



Figure 3. 1981 National summary of utility $SO_2$ and $NO_x$ emissions.

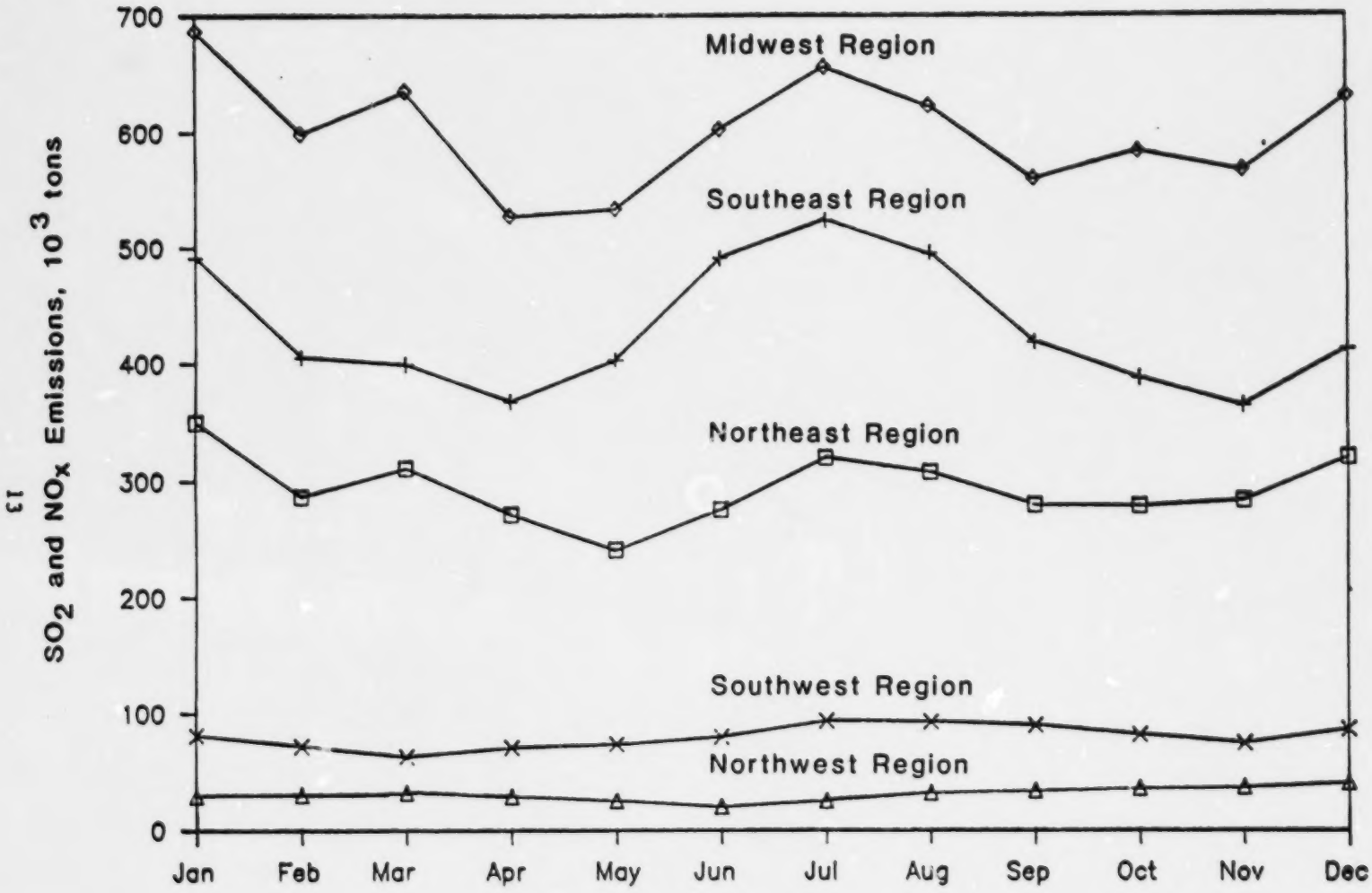



Figure 4. 1981 Utility monthly $SO_2$ emissions by region.

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